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Dynamics of Carbon Dioxide Transport in a Multiple Sink Network

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Abstract

As Carbon Capture and Storage slowly gets accepted and integrated as a mean for cleaner utilization of fossil fuels, the integration of capture, transport and storage becomes a key component to properly design a CO2 network. While the boundary conditions set by the capture and storage units have been the subject of much research, less attention has been paid to the challenges presented by the design and operation of full scale transport networks. Transport can however present a number of operational issues, especially due to the combination of horizontal and vertical flows, and the eventual presence of multiple injection wells. This paper provides an assessment of some issues occurring during transport of CO2 for injection in multiple sinks.

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Keywords: CO2; injection; transient; network; operation

1. Introduction

1.1. Background

As energy needs around the globe are rising, simultaneously with concerns about the environmental impact of human activities, Carbon Capture and Storage has been put forward as a way to mitigate the detrimental effects of fossil fuels as an energy source. Significant efforts were thus spent in the past decade to evaluate the technical and economic feasibility of mass CO2 storage, with most work focusing on (a) the capture of CO2 from flue gases via different processes and (b) the characterization of different

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kinds of reservoirs to evaluate their reliability as CO2 storing media on geological time scales. Less attention was paid to the task of transporting CO2 from the capture to the storing sites. However, transport and injection of CO2 as part of a complete CCS chain presents its own limitations and restrictions in the design of the entire chain. Proper analysis of the challenges associated to transport is therefore key to the design of an operable and economically viable CCS venture.

In the context of this paper, transport is defined from the outlet of the compressor or pump station up to and including the tubing of the injection wells. Detail aspects of the transport scenario being analyzed here correspond to injection into a depleted gas field. Such a reservoir type was chosen for it is the most probable candidate for CCS in Northern Europe. The overall conclusions drawn in this study are however not so much dependent on the type of reservoir used and can easily be extrapolated to other reservoir types or even depth, as was shown by Paterson et al. [1].

Apart from the economic constraints of expensive, large ID and often submerged pipelines, there are technical restrictions on the injection rates and injection conditions. These requirements on the injection stem from limitations set by, for instance:

- Thermal or hydraulic cracking in the reservoir due to the large influx of cold CO2.
- Well integrity of the tubing, casing and cement linked to large pressure and temperature gradients along the well.
- The possibility of CO2 hydrates forming in the near well bore area, due to the presence of water from the reservoir.
- Water or even carbon ice formation at low temperatures.
- Noise, pulsation and vibration induced by high flow velocities.

In the current study, the basics of CO2 transport and injection are first discussed independently to discuss the physics at play in horizontal and vertical sections of the transport system. A simple two well network is then analyzed to illustrate different steps in the development of a CO2 transport network. Operation of this network is addressed with emphasis on the decommissioning of one reservoir for injection into another.

1.2. Model description

The analysis presented in this paper is based on injection in a typical North Sea depleted gas field. Simulations were performed using OLGA v7.1.0 and the single component module for CO2 (using the Wagner equation of state[2]). This means that impurities and their effects on the multiphase behaviour of CO2 were not taken into account in this work.

The overall geometry is summarized in Figure 1. The CO2 is transported via a 16” pipeline up to the injection site. Pipeline lengths of 25km and 100km were investigated. The overall heat transfer coefficient for this pipeline was set at $U = 5\ W/(m^2.K)$, corresponding to a poorly insulated pipe. Outside temperature of the pipeline is taken at a constant 4°C, corresponding to the seabed temperature. The injection wells consist of a 7” diameter, 3.4km deep, 57˚ deviated well with a single injection zone. Heat transfer is modeled by assuming a constant U value along the well of $U = 9.5\ W/m^2K$. This value was determined using a baseline simulation using the thermal conductivity of the different materials constituting a typical well wall, including steel casings and tubings, annuli, cement and insulation. It matches typical U values of wells that can be found in open literature [3]. Such simplification has the advantage to speed up the simulations with very small error compared to a model using full heat transfer calculations. A vertical linear outside temperature profile is assumed, ranging from 120°C (at reservoir) to 10°C (at the wellhead). Simulations were performed to cover reservoir backpressure varying from low (50 bar) to high (300 bar), corresponding to a gradual fill-up of the reservoir with injection lifetime. One to three wells were modeled to investigate a range of operating scenarios corresponding to different stages of a network development, including shifting injection from a high pressure full reservoir into a lower pressure empty one. Only simulation results up to two wells are discussed in this paper.

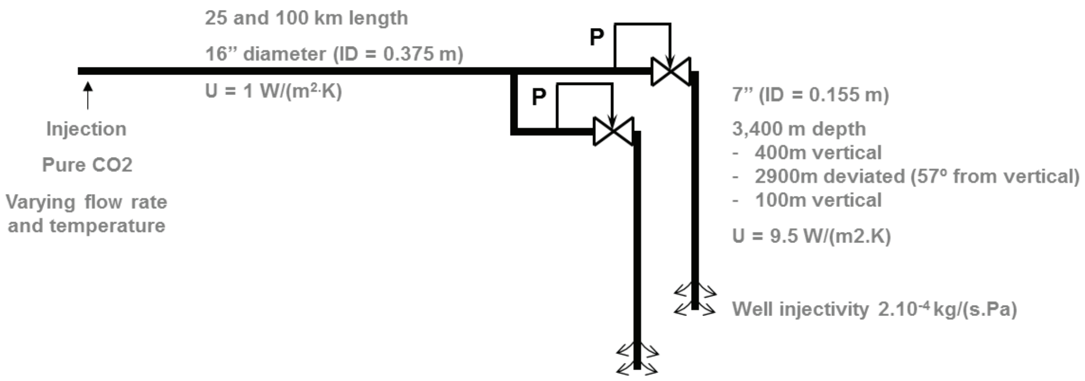

Figure 1: Schematic of pipeline routing for a two wells scenario.

The boundary conditions used for the simulations consist in (a) the reservoir pressure, set as a back pressure in the well model of OLGA, together with an injectivity of 2.10^{-4} kg/s/Pa, and (b) a fixed mass flow rate at the inlet of the pipeline, with a fixed CO2 temperature. Some of the simulations presented were performed with only one well or only the pipeline. For those, the inlet flow conditions were evidently adjusted. For all simulations, the thermodynamic relaxation time of CO2 was maintained at the default value of t = 1s. Other authors use very different values, such as 60s [4]. However, the available test data is not sufficient to validate either choice and therefore, the default and recommended value was maintained [5]. Finally, a minimum time step of 10^{-3}s and a maximum timestep of 5s were used for the simulations.

2. CO2 wellbore flow

When injecting into a well, the flow is fully determined by the wellhead temperature and flow rate and the reservoir pressure and injectivity. All other pressures and temperatures throughout the well can be determined from these inputs, including the wellhead pressure. Furthermore, the wellhead temperature is determined by the pipeline heat losses and the pipeline inlet temperature as is described in more details in the next section.

The pressure and temperature behavior in the well is almost fully dominated by the thermodynamics of the fluid. The pressure drop through the well is made up of two components: the gravitational and the frictional pressure drops:

$$\frac{\partial p}{\partial z} = \Delta p_{gravity} + \Delta p_{friction} = \rho g + \tfrac{1}{2}\rho u^2 \lambda \frac{1}{D}, \quad (1)$$

with $\partial p/\partial z$ and Δp the pressure gradients along the tubing [Pa/m], ρ the fluid density [kg/m^3], g the gravitational acceleration [m/s^2], u the fluid velocity [m/s], D the tube diameter [m] and λ the friction coefficient [-]. The gravitational pressure is the only component when a static column of fluid is present and corresponds to a hydrostatic head: it therefore tends to decrease the wellhead pressure compared to the bottomhole pressure. The frictional pressure drop corresponds to a pressure drop in the direction of the flow, due to friction. Since the flow is downward, its effect is opposite to the gravitational pressure drop: it tends to increase the wellhead pressure. In a production well, both of these components act in concert, resulting in the well-known Tubing Performance Curve (TPC).

Simulations of an injection well of geometry described in Section 1.2 were performed with varying reservoir pressure and mass flow rate and a fixed wellhead temperature of 4˚C and 20˚C. The pressure profile along the well is illustrated in Figure 2 for variation of the mass flow rate and reservoir pressure at a wellhead temperature T_in = 4˚C. For the higher mass flow rates, frictional pressure losses are dominant: CO2 loses pressures at a faster rate due to friction, as it travels down the pipe, than the pressure built up due to the hydrostatic column of CO2 above. For this pipe diameter (7" tubing), large flow rates are necessary to reach this condition. In fact, the injection rate of 200 kg/s (6.3 MTA) in this tubing corresponds to velocities within the well around 13 m/s. This is a relatively high velocity, as far as pressure drop is concerned and would not be recommended for normal pipeline flow. For an injection well, these velocities still present erosional risks. However if a clean particle free fluid can be guaranteed, these risks should be minimal. Vibrations risks are important and it should be taken into account in the completion design, such as tubing material and packer locations. For other intermediate flow rates, oscillations in the pressure profiles appear along the well (both during steady state and dynamic simulations) due to the presence of two phases along the well. In the same figure, the pressure profile is plotted for a fixed flow rate and varying reservoir pressure. It is interesting to note the similarity between these profiles. They are almost parallel, down to a reservoir pressure below 150 bara, when two-phase conditions occur around the wellhead. It should be noted that for these simulations (and these only), the bottomhole pressure was prescribed directly, rather than a reservoir pressure with an injectivity.

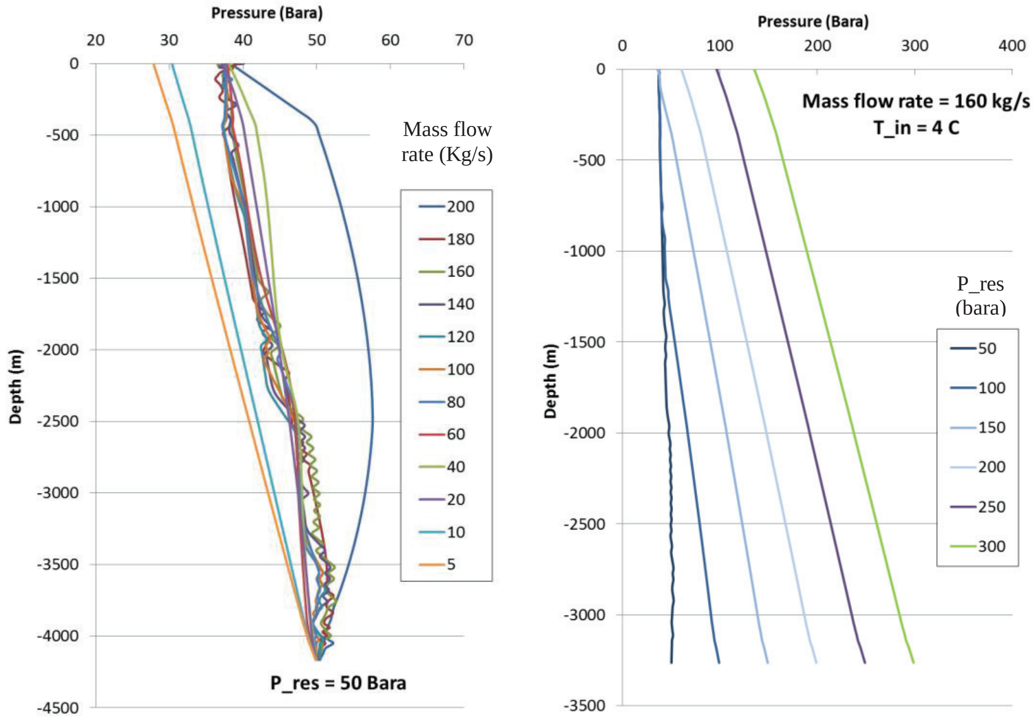

Figure 2: Pressure profile along the well for different flow rates and reservoir pressures for well head temperature of 4°C (Left: fixed reservoir pressure (200 Bara) and varying flow rate; Rightfixed flow rate (160 kg/s) and varying reservoir pressure).

The wellhead pressure as a function of mass flow rate for different reservoir pressures are then shown in Figure 3. For a given reservoir pressure, there is a range of flow rates for which the wellhead pressure is constant. This phenomenon occurs when CO2 at the wellhead is in the two-phase region, and result in wellhead conditions which are the same, independently of the reservoir pressure but dependent on the wellhead temperature. This range is much larger for the lower wellhead temperature of 4˚C compared to the 20˚C case. The former temperature corresponds to a flow that has cooled down to the sea bed temperature. This is of great interest for operation of a network where different wells, potentially drilled into different reservoirs or compartments and of different lengths could be operated with the same wellhead pressure. Discussions on this topic are presented in section 4. It should also be noted that for wells of smaller diameter, i.e. injection through for example a 5” casing, the frictional pressure drop is larger, resulting in a shift of the wellhead pressure curves to lower mass flow rates.

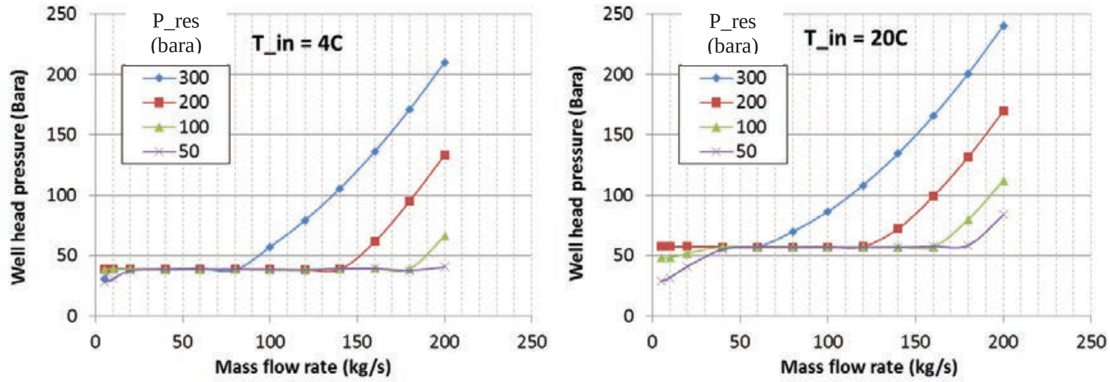

Figure 3: Wellhead pressure as function of mass flow rate for different reservoir pressures and fixed wellhead temperature of 4°C (left) and 20°C (right).

The downhole temperature and overall liquid volume ratio in the well are plotted in Figure 4 as a function of flow rate and for different reservoir pressures.

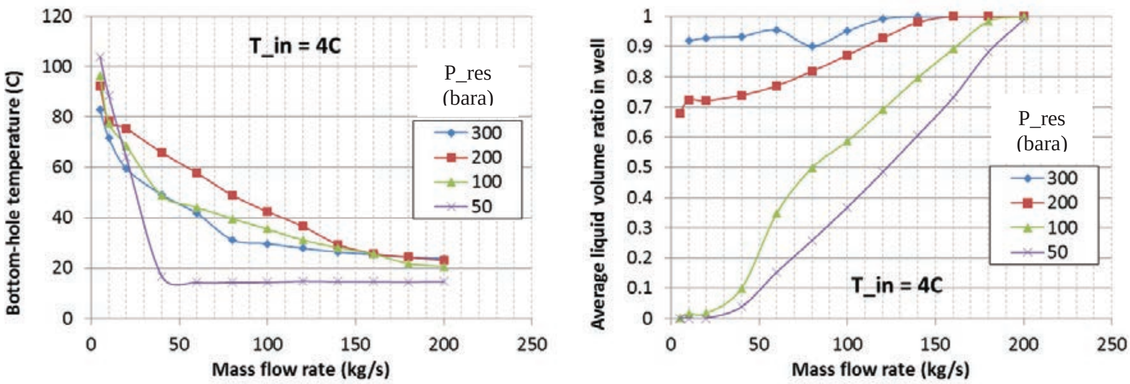

Figure 4: Bottomhole temperature (left) and overall liquid volume fraction (right) in the well as a function of flow rate and for different reservoir pressures.

At low flow rate, the downhole temperature is unsurprisingly high, partially due to heating through the casing, but mostly caused by compression of the CO2. As the flow rate increases, the downhole temperature decreases. For a reservoir pressure of 300 bar, this decrease is initially (at low flow rates) more rapid than for reservoir pressure of 200 bar. This is due to the fact that at these flow rates, the wellhead pressure is independent of the bottomhole pressure, therefore a larger bottomhole pressure translates into a larger pressure drop, and hence more heat dissipation via Joule-Thompson expansion. For lower reservoir pressure, the wellhead pressure is almost always constant (See Figure 3), leading to a different trend, where the temperature drop is more pronounced with lower reservoir pressure due to increase in gaseous CO2 as is shown in the same figure where the liquid volume fraction is clearly much lower for lower reservoir pressures.

3. CO2 pipeline flow

Simulations of CO2 flow in a pipeline can also be performed to identify the expected arrival temperatures and required compression power. It is not the intention to fully describe the process behind designing a CO2 transport pipeline. Some experience in this can be found in the literature [6], although guidelines and standards are still not adequate due to the lack of experience in transporting anthropogenic CO2. Nevertheless, for economic reasons, uninsulated pipes are likely to be used for offshore transport over great distances (of the order of 100 km). For such distances, the CO2 transported, will have cooled down significantly and since it was shown that the wellhead temperature is a key parameter to the flow within the well, this cooling rate needs to be described. The pipeline considered here is 16”diameter and poorly insulated (U value of 5 W/m^2K) laying on the sea bed, with an ambient temperature of 4˚C, which is typical for a Northern Europe case. In order to prevent two-phase to ever occur in the pipeline, an arrival pressure of 80 bara is prescribed at the wellhead. This pressure is above the critical pressure and should result in a single phase, regardless of the local temperatures. Steady state results of OLGA simulations of such simple flow are shown in Figure 5 for two flow rates. The prediction shows sudden variations in pressure and temperature toward the end of the pipeline which are suspicious. These large fluctuations occur above the critical point, where a virtual delimitation is still made within OLGA between supercritical CO2 and liquid CO2. In reality, CO2 properties vary smoothly, albeit significantly in this region, and such variations are not physical. Since OLGA is the preferred simulator for CO2 pipelines flow assurance studies, reliable simulations should be sought, and it is recommended for properly defined flow properties to keep the pressure higher than 80 bars.

Steady state simulations of 25km and 100 km pipelines are then performed to estimate the expected arrival temperature of the CO2, with the arrival pressure fixed at 100 bar. The simulator issues described above are completely avoided with this higher pressure. The arrival pressure as a function of mass flow rate is shown in Figure 6. Prior to the transport, CO2 compressed to high pressures (100-120 bara) typically exit the compressor train at temperatures ranging from 40 to 80 ˚C. Therefore, a range of inlet temperatures was used for these simulations. Lower mass flow rate results in lower arrival temperature (sea bed temperature) due to the lower velocity of the CO2, and therefore the longer residence time in the pipe. Even at high mass flow rates and high inlet temperature, the fluid has cooled down to around 20 ˚C at the outlet of the 100 km pipeline. Since transport lines are likely to be of a similar or much longer length (as for example the Karsto transport line [6]), it is reasonable to assume that the CO2 will have cooled down to sea bed temperature upon arrival at the injection site. This assumption will be used in the following multiple sinks simulations.

In practice, in order to maintain the pipeline pressurized during injection, a choke needs to be installed at the wellhead. Choking of the flow is not an issue if the fluid is in liquid phase before and after the choke as this results in negligible expansion and temperature drop. It may however result in considerable temperature drops when the choked flow reaches the phase line (below 38.5 bara for 4˚C). Operating the wells such that the wellhead pressure is high enough for CO2 to be entirely in liquid phase requires either a high flow rate, or to reduce the diameter of the injection tubing. This can be taken care during the design phase of the well but will also result in more stringent limitations in the maximum flow rate allowable.

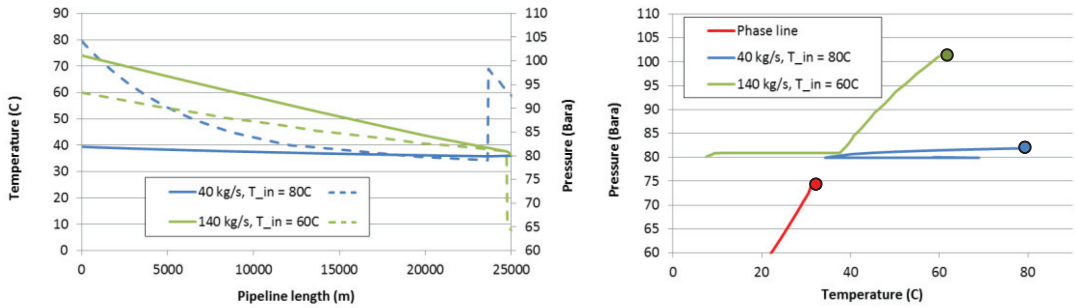

Figure 5: Steady state pipeline simulation results with outlet pressure fixed at 80 bars. Pressure and temperature along the pipe (left) PT diagram (blue and green dots representing pipeline inlet, red dot the critical point) (right).

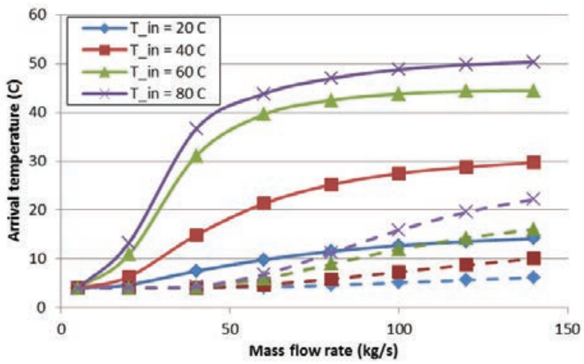

Figure 6: Arrival temperature as a function of flow rate for different inlet temperatures and inlet pressure of 100 bar. Plain lines: 25 km pipeline, dashed lines: 100km pipeline.

4. Operation of a two-sinks network

A network was analyzed, comprising of two wells of identical geometry connected to a single transport line (25km long, with inlet temperature set to -4˚C to simulate a much longer pipe). Each well was equipped with a 5” diameter choke, controlled via a proportional integral derivative controller (PID) to regulate the upstream pressure to 100 bara minimum. This ensures that two-phase flow will not occur in the transportation pipeline. In addition to this constraint, the compressor envelope at the pipeline inlet is assumed to be between 100 and 120 bara. This means that some large flow rates above 140 kg/s will not be achievable for reservoir pressure around 300 bara, as seen in Figure 3. These limitations in mind, simulations are performed to assess the operability of this two wells network.

Simulations are first shown in Figure 7, with slightly different bottomhole pressures between the two wells. The simulations were run dynamically to let the PID controllers adjust the choke settings of each well, until stable steady state flow profiles were obtained. The slightly different bottom hole pressures could for example occur due to a different depth of the wells or the presence of different compartments in the same reservoir. The dashed and solid lines respectively correspond to the high and low pressure reservoirs while the colors of the lines correspond to different total mass flow rates. In addition, the flow rate and choke openings for each well are shown in Figure 8. The wellhead pressures and temperatures from these simulations are the same for both wells, regardless of the prescribed mass flow rate. This has nothing to do with the presence of a PID on the wellhead choke (choke openings are strictly identical), but is simply due to the fact that for all these conditions, the wellhead pressure is bound onto the phase line (i.e. fixed to 38.5 bara for 4˚C CO2) This constitutes a self-regulating effect, with the flow rate being split equally between both wells, as illustrated in Figure 8: both the flow rates and the choke openings are identical,. However, it also means that as a compartment of a reservoir fills up faster than another (for example because it is smaller), the injected mass flow rate does not decrease, and its reservoir pressure keeps increasing at a faster rate than the other larger compartment. This phenomenon occurs until the pressure is such that the wellhead condition is not prescribed by the presence of two phases. For a flow rate (per well) of 100 kg/s, this corresponds to a reservoir pressure slightly lower than 300 bars, as seen in Figure 3. To illustrate this, similar simulation results obtained with reservoir pressures of 320 and 280 bara and a range of flow rates are reported in Figure 9. In these pressure profiles, the wellhead conditions are clearly different between the high and low pressure wells. The mass flow rates are also different, with higher mass flow rate toward the lower pressure reservoir, even though the choke openings are the same. Since the chokes act on both the pressure and temperature for both wells, it is possible that there exists, for some downhole pressure and flow rate conditions, some other possible choke settings other than this "trivial" solution (both chokes with the same opening). This is however not discussed in more detail here.

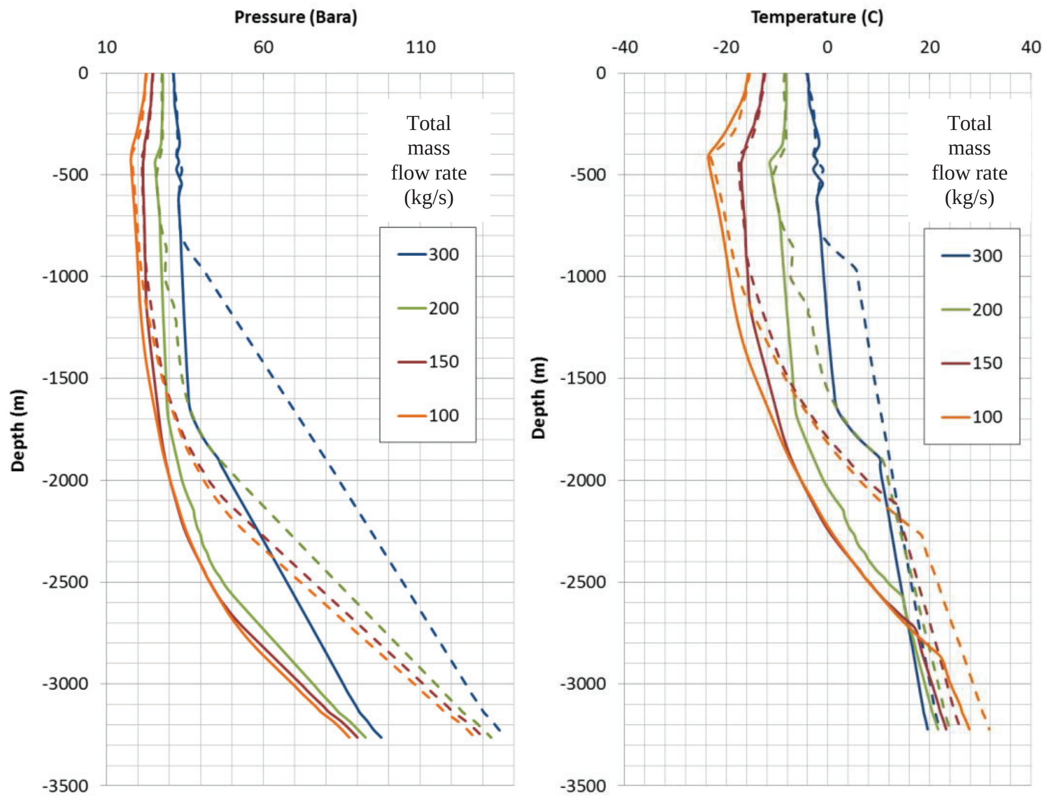

Figure 7: Steady state pressure (left) and temperature (right) along two connected wells, with reservoir pressures of 120 bara (dashed lines) and 80 bara (plain lines) and different total mass flow rates.

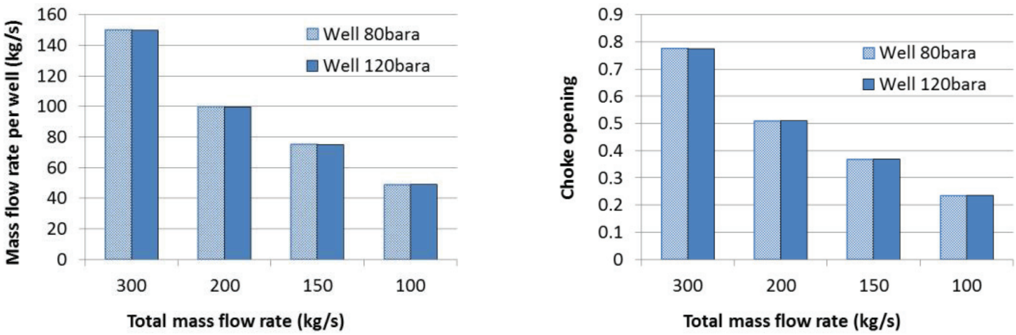

Figure 8: Calculated mass flow rates and choke settings for each wells of the simulations of Figure 7

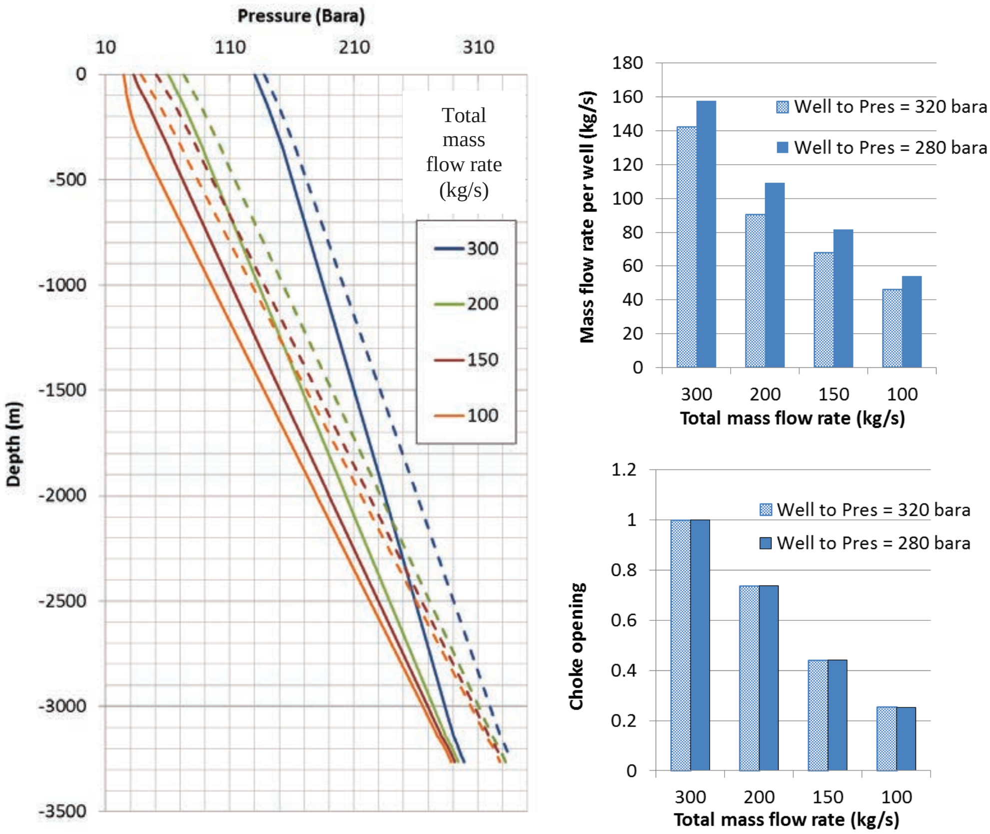

Figure 9: Steady state pressure (left), mass flow rate (top right) and choke opening (bottom right) per well along two connected wells, with reservoir pressure of 320 bara (dashed lines) and 280 bara (plain lines) and different total mass flow rates.

Finally, it should be remarked that the temperatures within the wells are quite low (Figure 7) due to the expansion of 100 bara liquid CO2 to a liquid/gas mixture around 30 bara. Temperatures as low as -15˚C occur at the wellhead for the lowest flow rate, with further cooling as gaseous CO2 expands while dropping down the well. This can be an issue for material specifications and can be avoided by setting a minimum allowable flow rate during injection.

Shut-down and restart of a single well are presented in Figure 10, again with the wells connected to a 25km pipeline and their chokes controlled via a PID controller to set the upstream pressure to 100 bara. In these simulations, the well connected to the 120 bara reservoir was shut-down suddenly (in 10s) at time t = 10h. All flow is therefore routed through the other well, connected to a 80 bara reservoir. At time t = 20h, the well is restarted again, also in 10s. There are no uncontrollable fluctuations during any of this entire process observed during these simulations. In the high flow rate case (300 kg/s total mass flow rate), the pressure on the wellhead of the well that remains open increases due to the added flow rate. This increased pressure would in practice not be supported by the compressor or pumping station upstream, which would force a lower pressure and therefore a decrease in flow rate. In both cases, low temperatures of the order of -40˚C are reached right after the shut-down of the well, due to expansion of gaseous CO_2. This however occurs during a very brief period of time and should not be sufficient to cause additional structural issue than the otherwise constant low temperature of around -15˚C.

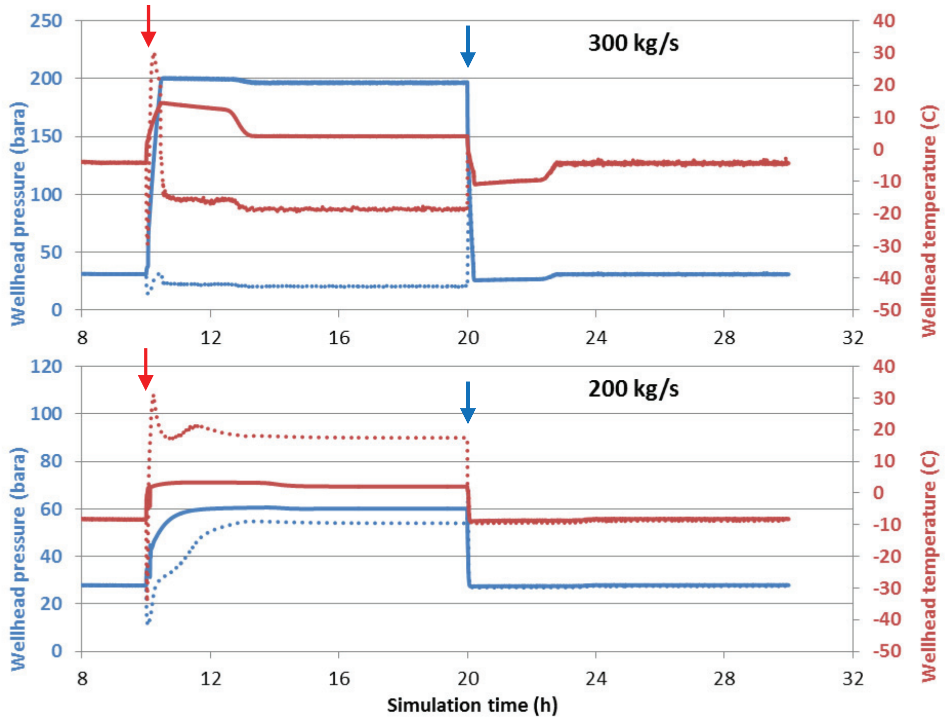

Figure 10: Evolution of pressure and temperature at the wellheads when injection is stopped in a well connected to a 120 bara reservoir (dashed lines) and carries on in the well within a 80bara reservoir (solid lines). The total mass flow rate is kept constant during the operation, injection in 120bara reservoir stopped at t = 10h (red arrow), and restarted at t= 20 h (blue arrow).

Simulations were conducted to investigate the feasibility to switch injection from one well linked to a high pressure (i.e. full) reservoir to another well that is connected to a 50 bar reservoir. Results of these simulations are shown in Figure 11 for a range of mass flow rates. In these simulations, a given flow is prescribed at the pipeline inlet, with a single well connected. Then at time t = 10h, inflow to a second well is opened (within 10s). This second well is connected to a low pressure reservoir. After 10h, the choke to the first reservoir is closed. These actions are performed with PID controllers still in place to regulate potential oscillations in the pressures.

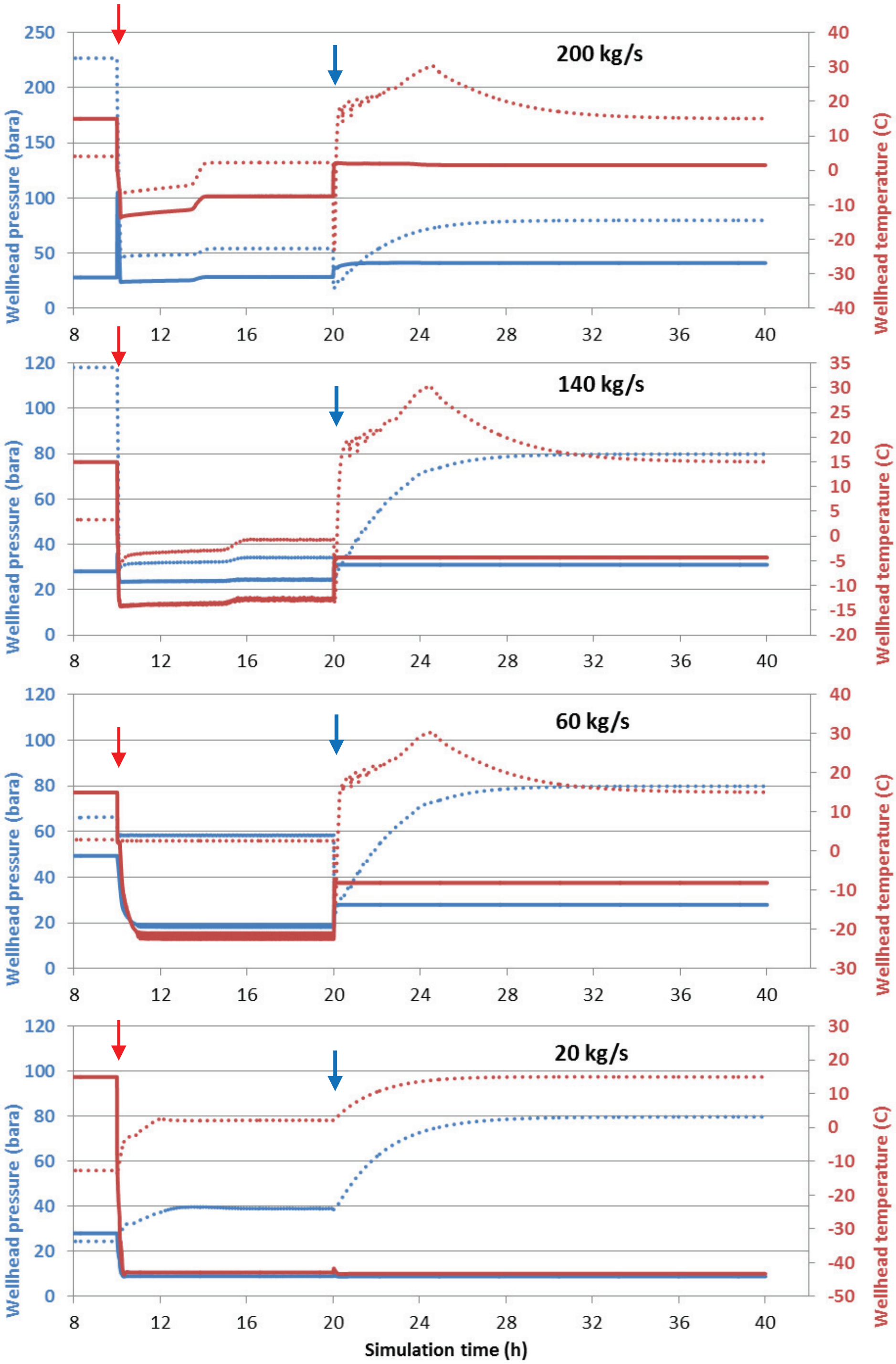

Figure 11: Evolution of pressure and temperature at the well heads when injection is switched from a well within a 300 bara reservoir (dashed lines) to a well within a 50bara reservoir (solid lines). Total mass flow rate constant during the operation, choke to 50bara reservoir opened at t = 10h (red arrow), choke to 300bara reservoir closed at t= 20 h (blue arrow).

The resulting pressure and temperature profiles are relatively smooth, with only a very small amount of oscillations observed at the wellheads. The transients can take in excess of 10h after shutting the initial well. The temperatures at wellheads can reach low values for low flow rates, but these are not different from what could be observed from a single well injection. This means that when injection should be switched from one well to another, the highest possible injection flow rate should be used in order to avoid low temperatures that could damage the wells. This should of course be within limits of the operating range of the compressor and pumping stations.

Note that these conclusions are valid for a larger range of pressure of the low pressure reservoir, as far as the flow rates are such that the wellhead pressure is dictated by the phase line. The very same figures can be obtained for example using a low-pressure reservoir with a pressure of 100 bara. Finally, while no results are presented with more wells (3 or more), the two wells case represents the most drastic situation. Flow conditions with 3 wells are in many respects similar, with less drastic transients, and much more operational flexibility.

5. Conclusions

Transport of CO2 in a network as a part of a full CCS chain has been addressed via numerical simulations. Dynamics of CO2 in vertical and horizontal pipes were first described, highlighting the challenges linked to smoothly operate a pipeline connected to a well. Placing a choke at the wellhead was recommended as a mean to keep the pipeline pressure high enough to prevent two-phase flow phenomena. The flow rate should also be kept such that the wellhead pressure is still above the phase line, preventing large temperature drop through the choke and in the top part of the well.

A simple network with two wells was analyzed for potential operational issues. Flow through wells connected to reservoirs of different pressures did not present any challenge. For a wide range of flow rates and downhole pressures, the total flow rate inherently splits in equal parts between the wells. Shut-down and restart procedures of a single well out of the two can be performed without undesired fluctuations, as well as switching injection from a full to an empty reservoir.

While these conclusions were drawn for an empirically chosen geometry and operating conditions (such as the wellhead temperature), they are applicable to a larger range of network designs.

Acknowledgements

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